CLIMATE CHANGE IMPACTS ON HIGH ELEVATION HYDROPOWER GENERATION IN CALIFORNIA'S SIERRA NEVADA: A CASE STUDY IN THE UPPER AMERICAN RIVER

DRAFT

WHITE PAPER

A Report From:
California Climate Change Center

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Preface

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The PIER Program, managed by the California Energy Commission (Energy Commission), annually awards up to $62 million to conduct the most promising public interest energy research by partnering with Research, Development, and Demonstration (RD&D) organizations, including individuals, businesses, utilities, and public or private research institutions.

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The California Climate Change Center Report Series details ongoing Center-sponsored research. As interim project results, these reports receive minimal editing, and the information contained in these reports may change; authors should be contacted for the most recent project results. By providing ready access to this timely research, the Center seeks to inform the public and expand dissemination of climate change information; thereby leveraging collaborative efforts and increasing the benefits of this research to California's citizens, environment, and economy.

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Executive Summary

Using the head potential and snow storage existing in high elevation basins of the Sierra Nevada Mountains, a number of utilities manage a complex infrastructure of hydropower generation systems that contributes significantly to all electricity generated statewide. These systems are fed by stream inflows generated by precipitation in winter months and snowmelt during the spring season. It is expected that under a climate change scenario California's hydrology would experience an earlier timing of streamflows. This shift is associated with the increase in temperature, leading to a higher proportion of precipitation falling as rain (as compared to snow) and an earlier spring snowmelt runoff. Those two effects could impact the operations of high elevation hydropower reservoirs with low storage capacity. They could induce a timing mismatch between energy generation and energy demand. Additionally, higher inflows in wintertime could lead to greater spillage and less overall energy generation.

In order to study these potential effects we developed a linear programming model of the 11-reservoir hydroelectric interconnected system, with storage capacity of over 425,000 AF and generation capacity of 688 megawatts (MW) operated by the Sacramento Municipal Utility District (SMUD) in the Upper American River watershed. Hydrologic conditions under climate change scenarios were developed considering the effects on locations close to the system, as predicted by the Variable Infiltration Capacity model run using climatic output from 2 GCMs run under 2 emission scenarios.

The results show that hydropower generation, in terms of energy generated and revenues, drops in all climate change scenarios as a consequence of drier hydrologic conditions. The drop is greater in terms of energy generation than in terms of energy revenues, reflecting the ability of the system to store water when energy prices are low, and then release water when electricity demand and prices are high (July through September). Contrary to our expectations, we found no clear effect on annual energy generation associated with either changes in the timing of inflows or the magnitude and occurrence of high flows.

A sensitivity analysis of the most relevant parameters in the system allowed us to understand how hydroelectric systems in different basins will behave under a climate change scenario. An increase in total storage capacity would allow the storage of more water arriving during winter and spring months to be used to generate electricity in summer months, improving overall energy revenues for all climatic scenarios including the historical condition. Reducing storage capacity would reduce this ability to "move" water in time and forces the system to generate at a pattern closer to the hydrograph pattern. Under neither storage capacity scenario was there a clear effect of the earlier timing of inflows associated with climate change conditions. The reason: the pattern of energy prices throughout the year is not correlated with either the historical or the climate change hydrograph, so there is no loss of generation due to the hydrograph timing change. This was revealed when we performed a final scenario in which we changed the energy price for the month of June, which originally was set at a very low

value (1.8 cents/kWh) as compared to the energy prices in the three following months July-September (3 cents/kWh). Running the model with a reduced storage capacity and this new energy price pattern showed a clear impact on those climate change conditions that had a significant earlier streamflow pattern.

Another issue we understood through this sensitivity analysis is that the system as modeled in this project can handle large streamflow events minimizing the amount of water spilled without passing through the turbines. There are two major aspects that contribute to this ability to handle high flow events:

There is a multitude of reservoir interconnections existing in this system, which allow the use of water spilled from one reservoir (that has reached some capacity constraint) to generate in the same month using a reservoir downstream with idle capacity.

We have assumed the system acts with perfect foresight in terms of daily streamflow, within a month horizon. This power of perfect foresight allows system to operate in a rather unrealistic way that accommodates the advent of large streamflow events. A refinement to the model used in this project could include a smaller time horizon for the daily optimization (5-7 days) that will better reflect the uncertainties associated with potential flood events and the reliability limits of current weather forecasting models. This refinement would also better capture their associated impacts under a climate change scenario.

As the result of this analysis we expect that hydroelectric systems located in basins with significant inflows close to summer months will be affected by the timing effects associated with climate change conditions if they lack sufficient storage capacity to accommodate these changes (both storage capacity to hold water until it is needed to generate electricity, and capacity to absorb late high flows). The generation of any high Sierra hydroelectric systems with sufficiently large storage capacity should *not* be affected by these timing changes. There is still more work to be done to fully investigate the effects that a change in maximum reservoir inflows might have on the operation of the system. This will require a better representation of the uncertainties faced by the operators of the systems and will be included in future refinements of this work.

1.0 Introduction

Using the head potential and snow storage existing in high elevation basins of the Sierra Nevada Mountains, public and private utilities manage a complex infrastructure of hydropower generation that makes up almost 50% of all hydro electricity generated statewide (Aspen Environmental and M-Cubed, 2005). These systems vary in terms of storage capacity, conveyance capacity and altitude. Those systems with very little storage capacity (run of river systems) generate electricity as a function of streamflow (or releases from upstream reservoirs) and are unable to store flows in excess of their turbine capacities. In cases where storage is more significant the system is able to store excess water and release it through the turbines at a later time. Two important objectives in the operation of a hydropower system are (1) to generate during those periods when demand is higher and hence energy is more valuable, and (2) to minimize unnecessary spilling (water lost without electricity generation). Note that, in California, peak energy demand occurs during hot summer afternoon hours rather than in the winter.

The most consistent prediction of previous studies on the effects of climate change on California hydrology is an earlier timing of streamflows over the next 100 years. These shifts are associated with the increase in temperature, leading to a higher proportion of precipitation falling as rain (as compared to snow) and an earlier spring snowmelt runoff. Those two effects could impact the operations of high elevation hydropower reservoirs with low storage capacity. They could induce a timing mismatch between energy generation and energy demand. Additionally, higher inflows in wintertime could lead to greater spillage and less overall energy generation.

The purpose of this paper is to study the potential effects of climate change-induced hydrological changes on high elevation hydropower generation in California. The study has focused as a case study on the Sacramento Municipal Utility District (SMUD) hydroelectric system, located in El Dorado County within the Rubicon River, Silver Creek, and the South Fork American River drainages. SMUD's system is known as the Upper American River Project (UPAR), licensed by the Federal Energy Regulatory Commission as Project No. 2101. This project was constructed between 1957 and 1985. It includes 11 reservoirs that can impound over 425,000 acre-feet (AF) of water, eight powerhouses that can generate up to 688 megawatts (MW) of power, and about 28 miles of power tunnels/penstocks. The project is currently in a FERC re-licensing stage, which has allowed us to obtain a sufficient amount of publicly available data necessary for our case study (*SMUD* 2001).

2.0 Methodology

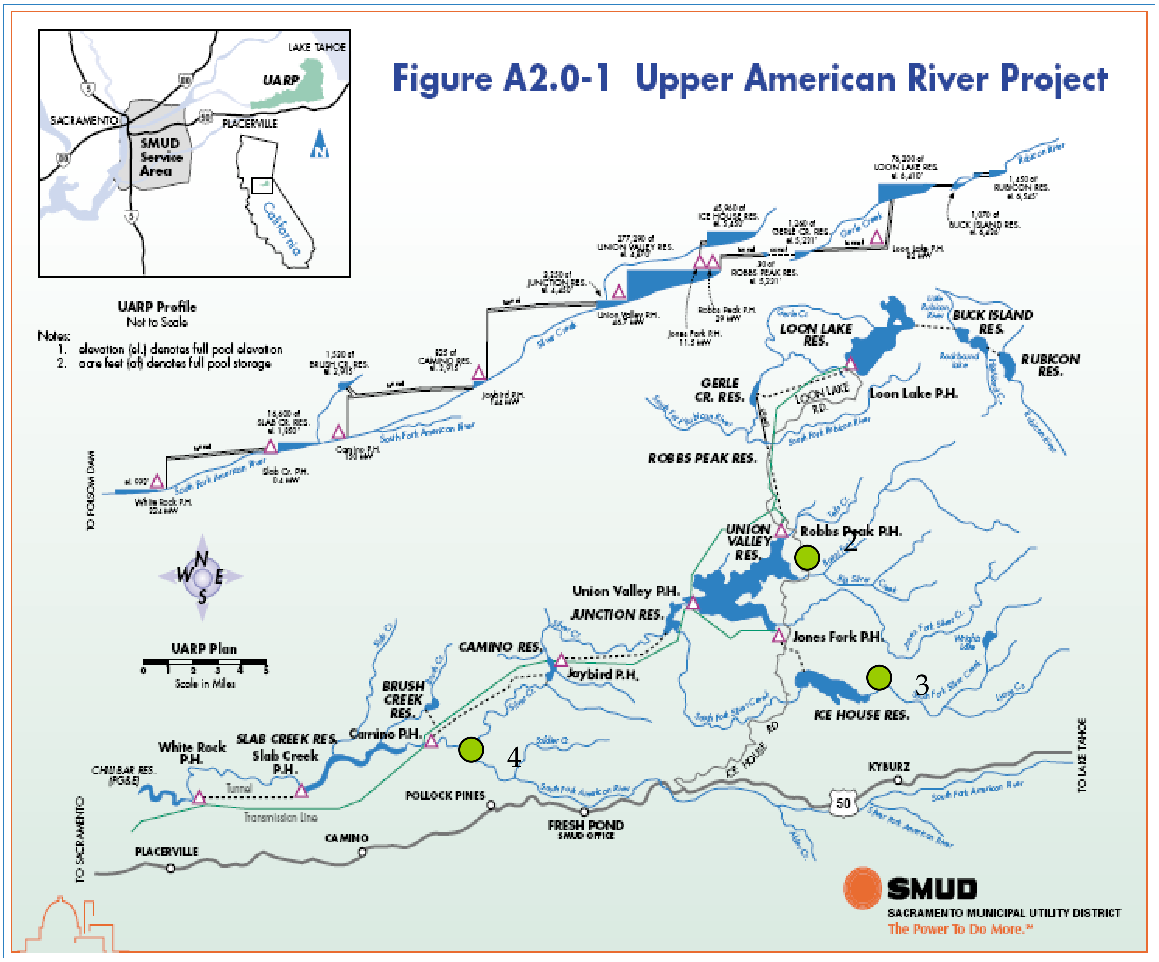
Our approach to study these impacts consisted of the following steps:

- Constructing a timeseries of daily and monthly historical unimpaired streamflows into the system using USGS streamflow data where available (and extensions of the same by correlation analysis)
- Perturbing daily and monthly data using climate change (for the 4 GCMs/emission scenarios) signals for VIC grid points located close to the system
- Performing a sequential, multi-step, linear optimization of energy production for the system under both the historical and the climate change conditions, assuming constant head. Under each sequence there will be one month optimized at a daily time step and the subsequent 11 months optimized at a monthly time step. This avoids the use of carryover value functions and minimizes some of the bias associated with the perfect foresight approach. Output from this step, which we will be comparing for different hydrologic scenarios, are average monthly energy production and value and spill amounts.
- Performing a sensitivity analysis on a key parameter of the system (storage capacity divided by average inflows) to understand how other systems with different storage capacities might respond under the same kind of climatic stresses.

The following section describes these steps in more detail.

2.1. Development of Historical Timeseries

The SMUD Upper American Project is located in El Dorado County within the Rubicon River, Silver Creek, and the South Fork American River (SFAR) drainages. Figure 1 shows a map of the system and a schematic of its major components. Four major rivers/creeks feed into the Upper American Project: the Rubicon River, Silver Creek, South Fork Silver Creek and South Fork American River. These inflows are denoted in Figure 1 by numbers 1 to 4, respectively. Information about the watersheds is summarized in Table 1. A major effort in this project was to develop an overlapping record of daily inflows to the system for a period before the projects were built (i.e. a record of unimpaired daily streamflow). Fortunately, two of the watersheds that feed into the system have daily streamflow USGS gage records dating back into the 1920s (gages 11441500, on South Fork Silver Creek near Ice House and 11441000, on Silver Creek at Union Valley). Inflow representing the Rubicon river was constructed to match a 1934-1950 flow prediction reported by Bechtel in 1958 and reprinted by SMUD (2001). This was built using correlation with USGS monthly streamflow data from nearby gauging stations (the adjusted R^2 in the correlation analysis was greater than 0.99 except for 1940-43, when it was 0.90). Finally, daily and monthly streamflow were estimated for the same period (1924-1960) for the full flow of the South Fork American River where it meets Silver Creek. Unfortunately, no gauging station measured streamflow throughout the study period on the South Fork near this confluence. Correlating daily USGS streamflow data downstream of the gauging station with contributions from Silver Creek (station 11442000) and gauging station 11439500, which is upstream of several tributaries, indicates that the South Fork contributes about 1.3 times the flow at station 11439500. This relationship was used to derive both daily and monthly inflows from the South Fork American River.



Source: SMUD, 2001

Figure 1. Upper American River Projects

Table 1: Study Basins

River	Reservoir(s)	Storage Capacity (af)	Site Elevation (ft)	Drainage Area (mi^2)
Rubicon	Rubicon Res.	1,450	6,545	26.1
	Rockbound Lk.			
Rubicon	Buck Island Lk.	1,070	6,436	14.2
	Loon Lake	6,436	6,410	(all three)
South Fk. Silver Creek	Ice House Res.	45,960	5,450	27.2
Silver Creek	Union Valley	277,290	4,870	83.7

Source: SMUD (2001)

A time period covering years 1928 through 1949 was selected to represent historical conditions in the system. As this was before the installation of the reservoir system, the data represents mostly unimpaired streamflow. Figure 2 shows monthly average streamflow conditions for Silver Creek representing inflows into Union Valley reservoir. The data shown are mean daily flows within the month, as well as the maximum and minimum daily stream flows of each month, as averaged over the study period. The streamflow pattern shown includes two peak natural streamflow conditions, a smaller peak occurring in winter (floods) and a larger peak occurring in spring (snowmelt runoff). Flows drop significantly in July. Figure 3 shows the same data for South Fork Silver Creek, representing inflows into Ice House reservoir. The pattern is similar to Figure 2 perhaps with a more pronounced hump for maximum stream flows in winter. The other 2 inflows to the system reservoirs (not shown) share a common pattern with South Fork Silver Creek.

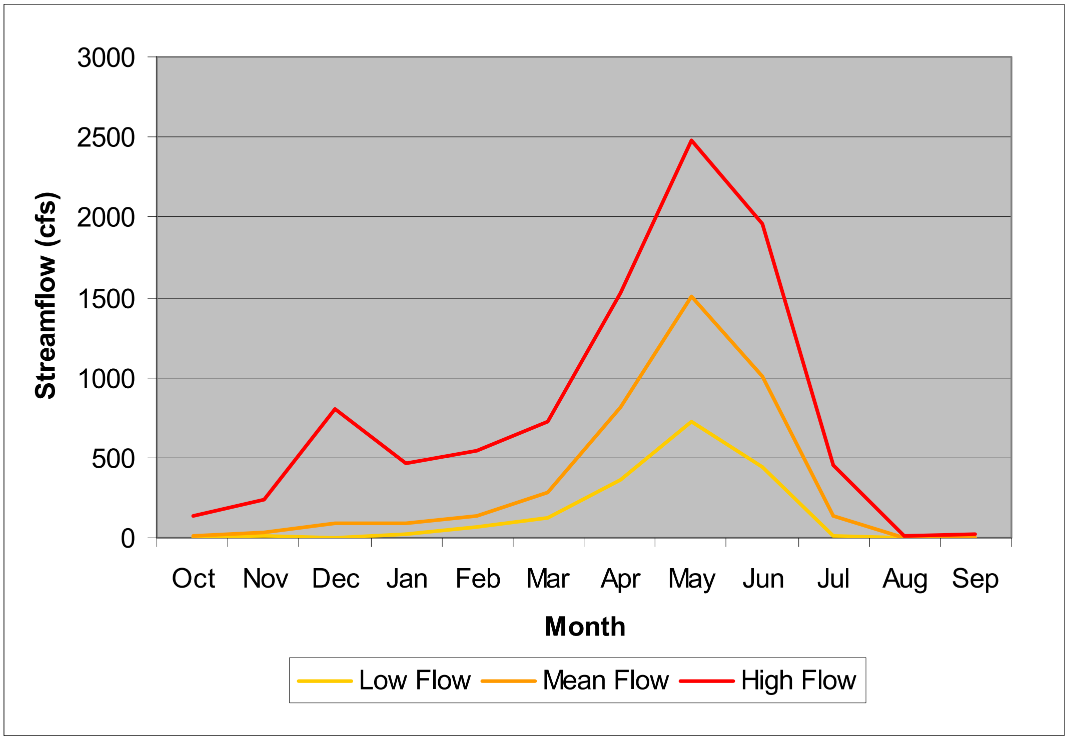


Figure 2. Unimpaired (pre-dam) inflows to Union Valley, 1928-1949 (Historic scenario)

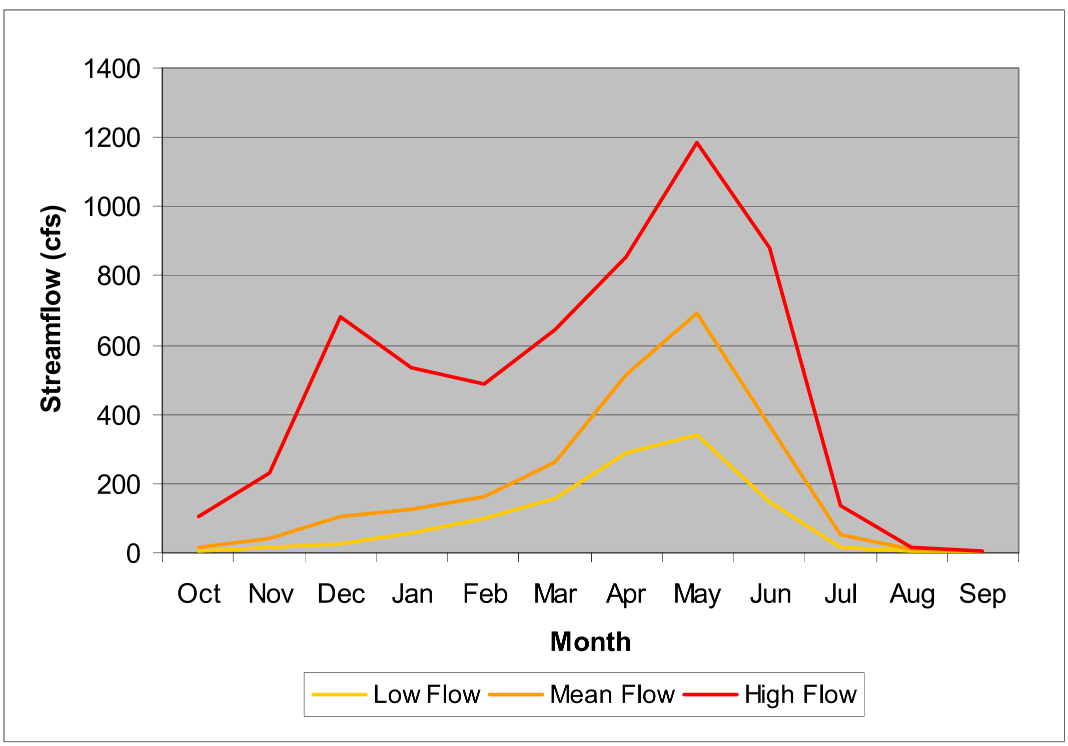


Figure 3. Unimpaired (pre-dam) inflows to Ice House, 1928-1949 (Historic scenario)

2.2. Development of perturbation ratios

Eight sets of daily and monthly streamflow predictions were used to develop perturbation ratios. These eight data series are hydrologic representations of streamflow at the two closest VIC grid output locations (Lat/Long: 39.0625/120.1875 and 38.8125/120.4375, denoted hereafter as grids 39 and 38), based on climate output as predicted by the NCAR PCM and GFDL CM2 climate models run under the GHG emission scenarios SRES A2 and SRES B1. Unimpaired natural streamflow representing the period 1960-1990 as predicted by the GCM (not actual historical streamflow) was compared with streamflow predictions for 2070-2099.

The perturbation ratio is a simple ratio of stream flows predicted by a GCM for different eras, for the corresponding time period (i.e. month). This can then be used to perturb an historical data series as an alternative to using pure model output. The development of monthly perturbation ratios was a straightforward procedure that consisted of obtaining streamflow averages for each month in both the historical and future climate change predictions. Figure 4 shows the monthly perturbation ratios for the 8 climate change scenarios.

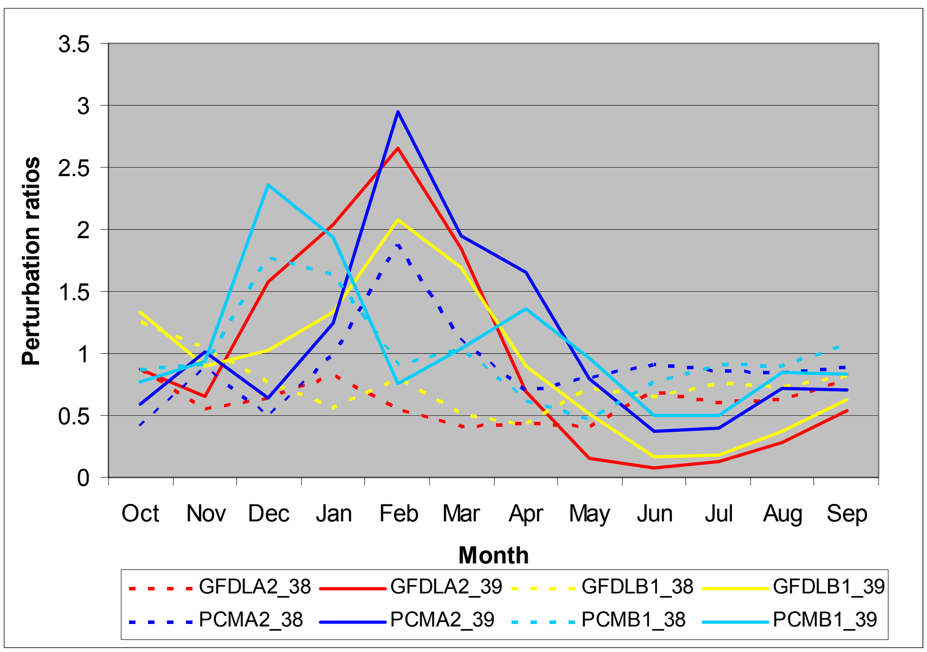


Figure 4. Monthly perturbation ratios (based on 2070-2099 climate change conditions)

The general trend that can be appreciated from these perturbation ratios is a decline in spring and summer stream flows and an increase in stream flows in winter (perturbation ratios lower and larger than 1 respectively). This translates into an earlier timing of inflows. The behavior is similar under all scenarios except the two GFDL predictions for grid 38, where we do not see increases in any given month. (It is not clear why the results in this grid are so different from the results for the other scenarios). In order to get a representative sample of all potential impacts we have included the following climate scenarios in our analysis: GFDLA2_38, GFDLA2_39, PCMB1_38 and PCMB1_39.

To develop the daily perturbation ratios for these scenarios we divided each month into equal sized sets of wet, normal, and dry days.[1] Averages were then taken of all wet January days, all normal January days, and so on, for both the historical and climate change predicted periods. This yields three series of monthly perturbation ratios for each climate change scenario, allowing us to track both average and extreme hydrograph changes. Daily perturbation ratios are shown in Figure 5 for all climate scenarios considered in the analysis. The results show that in general daily maximum stream flows increase more than medium and low stream flows. The clearest example would be the case of the GFDLA2_39 scenario. Figures 6 and 7 show the translation of these perturbation ratios into our simulated streamflow conditions, comparable to Figures 2 and 3. The results show the expected earlier timing of inflows and, interestingly, a more pronounced hump of flood conditions in winter months. The most extreme case would be GFDLA2_39, which basically shifted the high streamflow timing from May to February. In Table 2 we show changes to annual streamflow for the whole system for all scenarios.

[1] Generally the extra day would be added to the normal set, so that January has 10 wet, 11 normal, and 10 dry days.

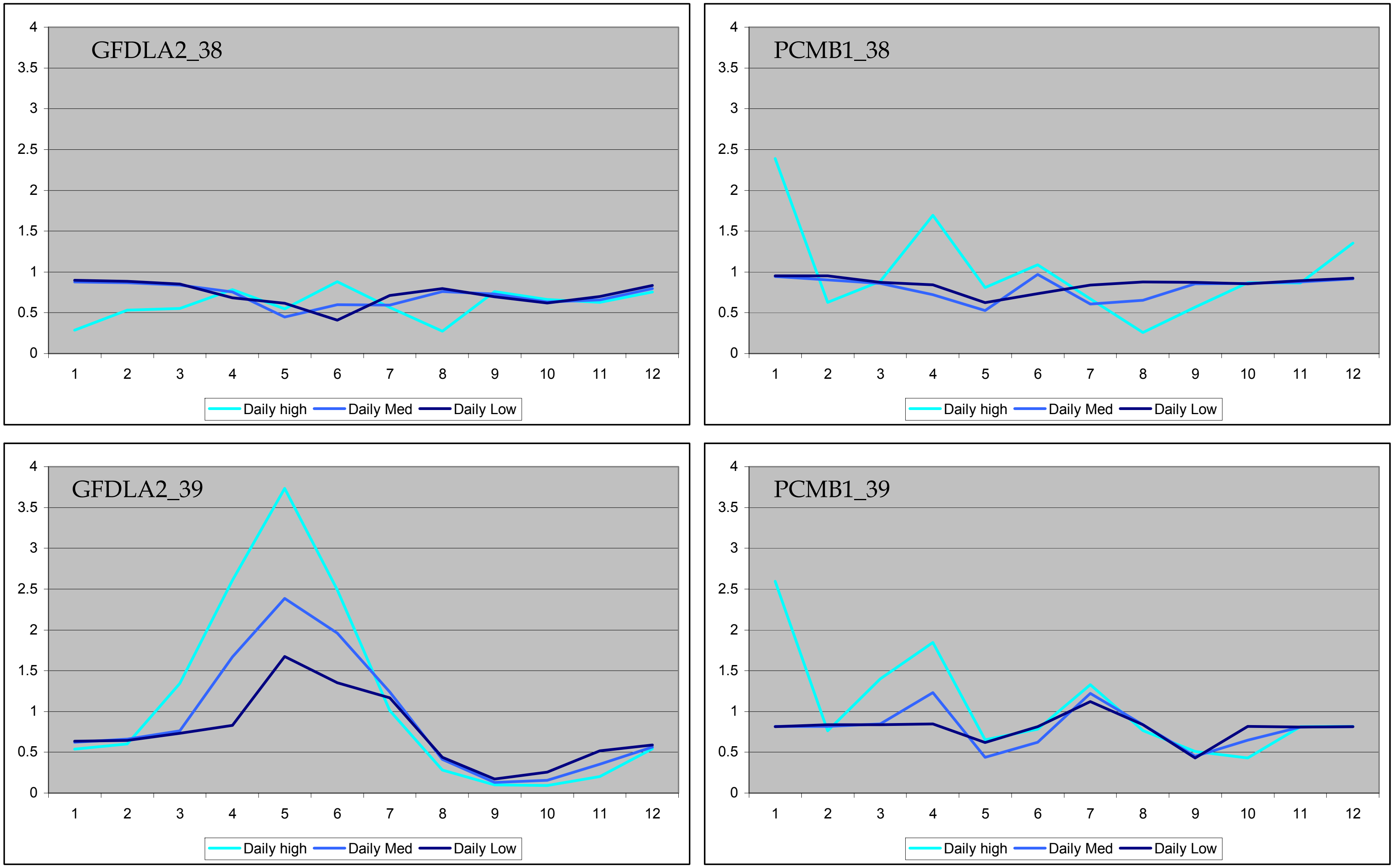


Figure 5. Daily perturbation ratios (based on 2070-2099 climate change conditions)

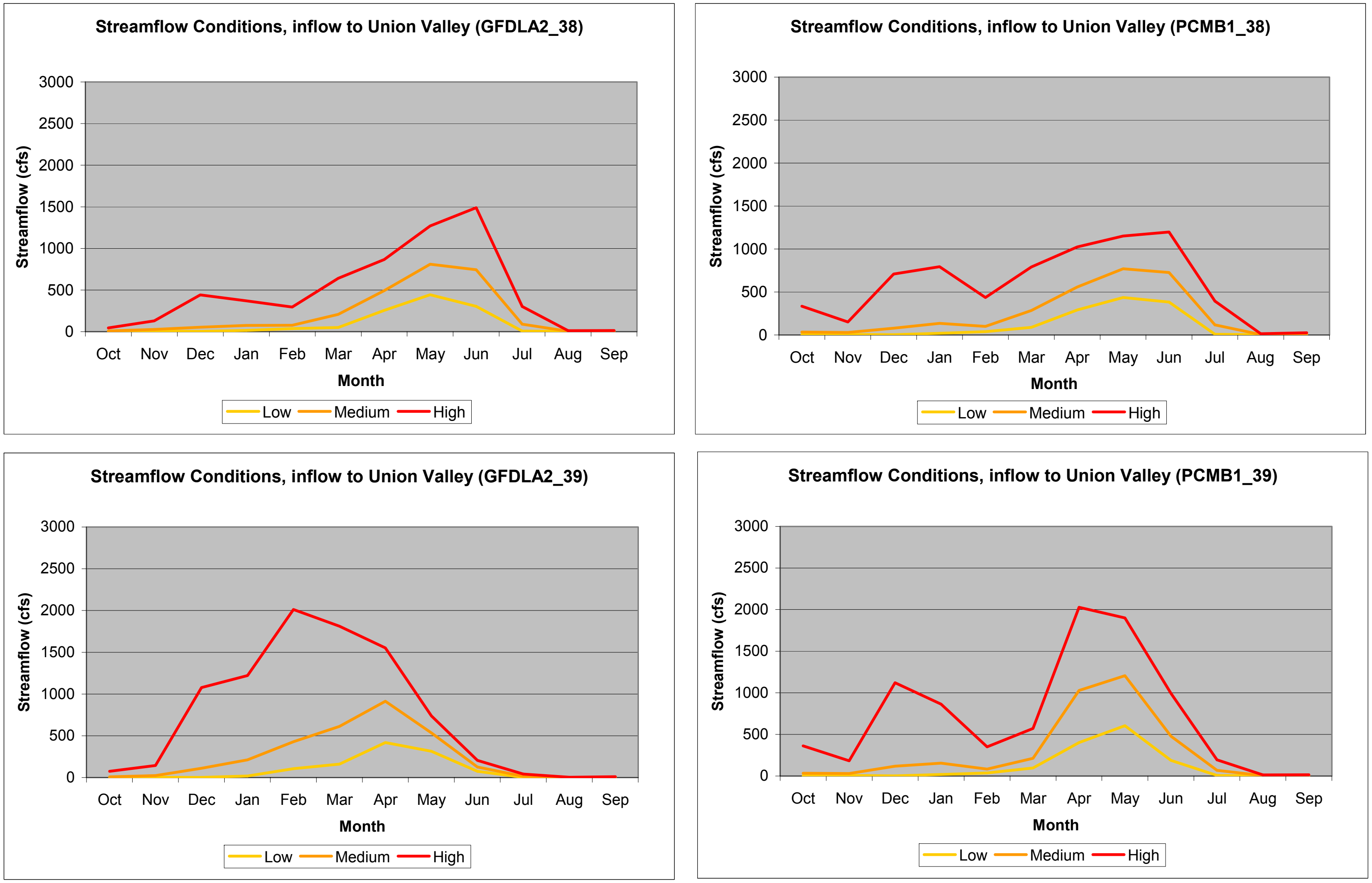


Figure 6. Streamflow conditions (unimpaired inflow to Union Valley) under Climate change scenarios, 2070-2099

Figure 7. Streamflow conditions (unimpaired inflow to Ice House) under Climate change scenarios, 2070-2099

Table 2. Change in annual average streamflow (in TAF/year and as percent of historical inflow)

	Scenario				
	Historical	PCMB1_38	PCMB1_39	GFDLA2_38	GFDLA2_39
Annual Average Inflow into System	491	348 (71%)	420 (86%)	307 (62%)	422 (86%)

2.3. Linear programming model

The SMUD hydroelectric system in the Upper American River is composed of 11 reservoirs that can impound over 425,000 acre-feet (AF) of water, eight powerhouses that can generate up to 688 megawatts (MW) of power and about 28 miles of power tunnels/penstocks (see Figure 1). Several of the reservoirs in the system are small and we assume they can be aggregated (according to the powerhouse into which they release water) without losing important operational components.[2] In Table 3 we show the basic characteristics of the 7 main components used to represent the system.

A multi-step linear optimization model was developed to represent system operations under different hydrologic scenarios. The objective of the optimization is to maximize energy generation revenues, restricted to operational constraints such as minimum instream requirements and physical constraints such as turbine or reservoir capacity. We used monthly energy prices considered in the CALVIN model formulation (see Appendix D of Lund et al., 2003).[3] In calculating energy generation it was assumed that the head remained constant throughout the optimization. This allowed the representation of the optimization problem as a Linear Programming (LP) problem. This assumption is reasonable where the maximum depth of a reservoir is much smaller than the head drop used to generate hydropower, and because all but two of SMUD's power plants are supplied by penstocks. Reservoir fluctuations are a very small fraction of the gross head provided by these penstocks. Table 3 shows the head of each powerhouse as compared to the maximum reservoir depth from which water is released into the powerhouse, and the powerhouse capacity. By looking at the table it is clear that the constant-head assumption is reasonable for most of the system components except

[2] Considering that there might be some operational oversimplifications on the Rubicon river system by doing this aggregation, we will consider a system representation of all 11 reservoirs disaggregated in future work.

[3] As explained at the end of this paper, in future refinements of this work we will repeat our analysis using a different set of monthly energy prices based on California Energy Commission analysis of historic values.

Table 3. System components included in the model

Parameter	Loon Lake	Robbs Peak	Union Valley	Jones Fork/Ice House Res.	Jaybird	Camino	White Rock/ Slab Cr. Res.
Head (ft)	1099	361	420	581	1535	1066	856
Reservoir Capacity (AF)	78720	1260	277290	45960	3250	825	16600
Reservoir depth (ft)	165	21	360	52	141	76	186
Depth/Head	15%	6%	86%	9%	9%	7%	22%
Penstock flow capacity (m3/seg)	28.3	35.38	44.63	8.24	38.06	59.43	111.79
Capacity (MW)	82	29	46.7	11.5	144	150	224

Union Valley. The capacity of that powerhouse is less than 10% of the total capacity, so we would not expect significant changes in the final results with a dynamic representation of reservoir depth.

In Appendix A, we present a more detailed description of the LP formulation.

A moving horizon of 12 months determined the time period over which the optimization was performed. The first of these months had a daily time step and the remaining 11 months were modeled at monthly time steps. The use of a daily time step within the first month allowed the assessment of impacts due to differences in the relative size of flood events, crucial to the outcome of the system operation with regards to undesired spill. The use of an 11-month horizon in the monthly optimization avoids the need for an end storage value necessary to prevent excess releases of streamflow through the turbines, the result of myopic behavior.

It is unclear at this moment how much the "perfect foresight" condition used for the daily operations affects the results of the operations under different hydrologic scenarios. A future modification of our approach to explore this issue would be to use the 12-month moving horizon optimization with a monthly time step at each month. The optimal releases for the first month could be used as "release targets" in a daily time step simulation model.

3.0 Results

The LP model was run under all 5 hydrologic scenarios. The outputs we were interested in were: revenues from hydropower generation, monthly energy generation, and spills. The comparison between scenarios is shown in Figures 8-10. Figures 8 and 9 show hydropower revenues (in nominal $/month) and hydroelectric energy generation (in MWh/month) for the whole system of 7 powerhouses. Figure 10 shows spills in average cfs. Included in these figures for reference is the monthly energy value used in the objective function. It can be seen that all scenarios show a pattern of generation similar to the monthly pattern of the energy value, with maximum generation during the summer months and minimum during spring and winter. However, the drop in generation (and hence revenues) during spring months is higher for the future climate scenarios than for the historical conditions. These are the months with lower energy value, so a plausible explanation for this effect is that under the climate change scenarios that predict a decrease of inflows to the system, generation is reduced in the least valuable months. The reduction in annual revenues (generation) as shown in Table 4 ranges from a 30% drop to an 11% drop. When we compare these changes with changes in annual streamflow conditions (see Table 5) we see that for the most part, changes in annual stream flows are driving the changes in total generation. However the changes in annual inflows are normally higher than the changes in generation revenues. This means that the system is able to continue moving water (in time) to more valuable months, reducing the economic effect that a drop in annual inflow might otherwise have. We would expect this ability to increase as inflows are further reduced because more storage capacity is freed up. We see this when we compare the relative difference between drops in revenues and drop in annual inflow (or generation) for the scenarios analyzed. For example, scenario PCMB1_38 had a drop of 29% in inflows but only 23% in revenues, while scenario PCMB1_39 had a drop of 38% in inflows but only 30% in revenues.

Table 4. Change in annual output from the system (as absolute value and percent of historical output) (average of historic and perturbed 1928-1949 period)

	Generation Dollar/year		MWh/year		Average Monthly Spills (cfs)
Historical	37319340		1422699		35
PCMB1_38	28641080	77%	1025497	72%	3
PCMB1_39	33323870	89%	1233249	87%	18
GFDLA2_38	25973640	70%	914564	64%	1
GFDLA2_39	32589481	87%	1208190	85%	42

Table 5. Comparison between changes in hydropower generation and in annual inflows to the system (as a percent of historical output) (average of historic and perturbed 1928-1949 period)

	Change in Generation		Change in Annual Streamflow
	Dollar/year	MWh/year	
PCMB1_38	77%	72%	71%
PCMB1_39	89%	87%	86%
GFDLA2_38	70%	64%	62%
GFDLA2_39	87%	85%	86%

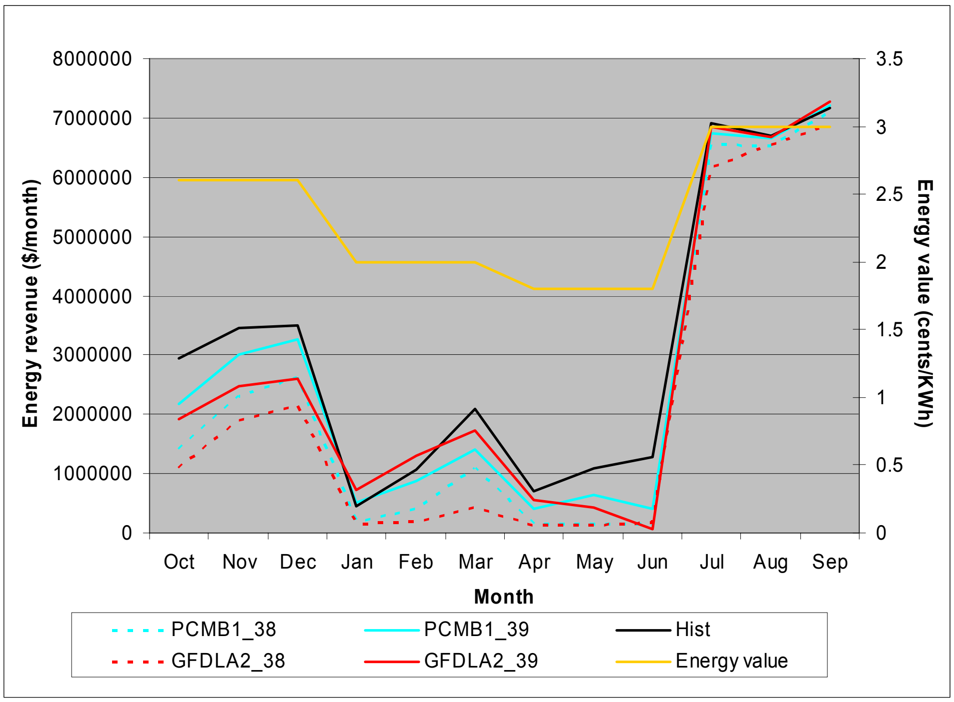


Figure 8. Energy revenues: comparison of scenarios

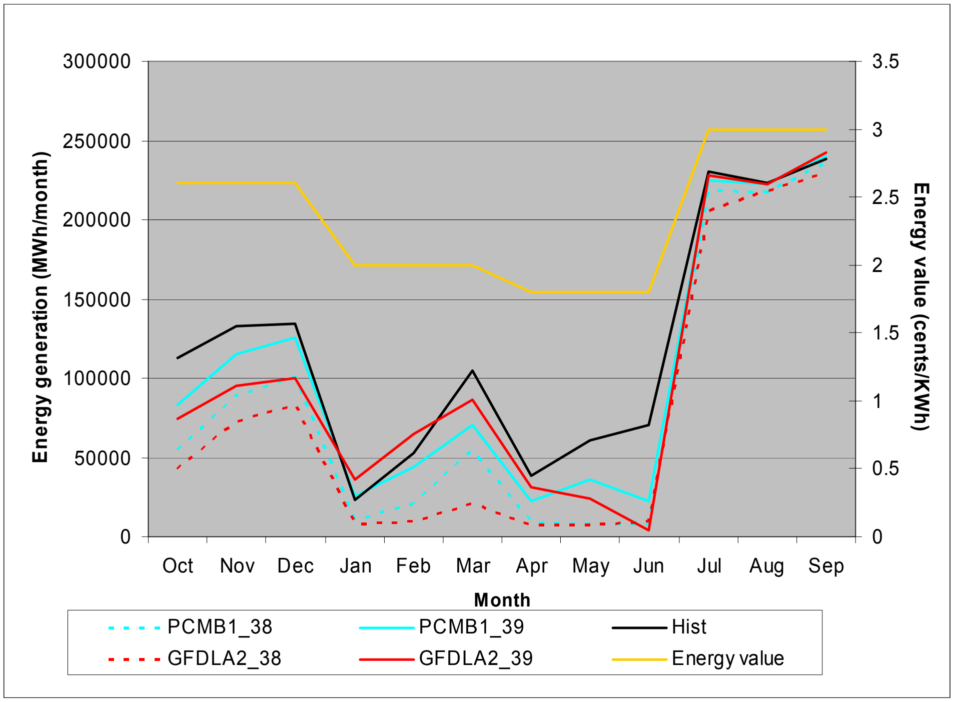


Figure 9. Energy generation: comparison of scenarios

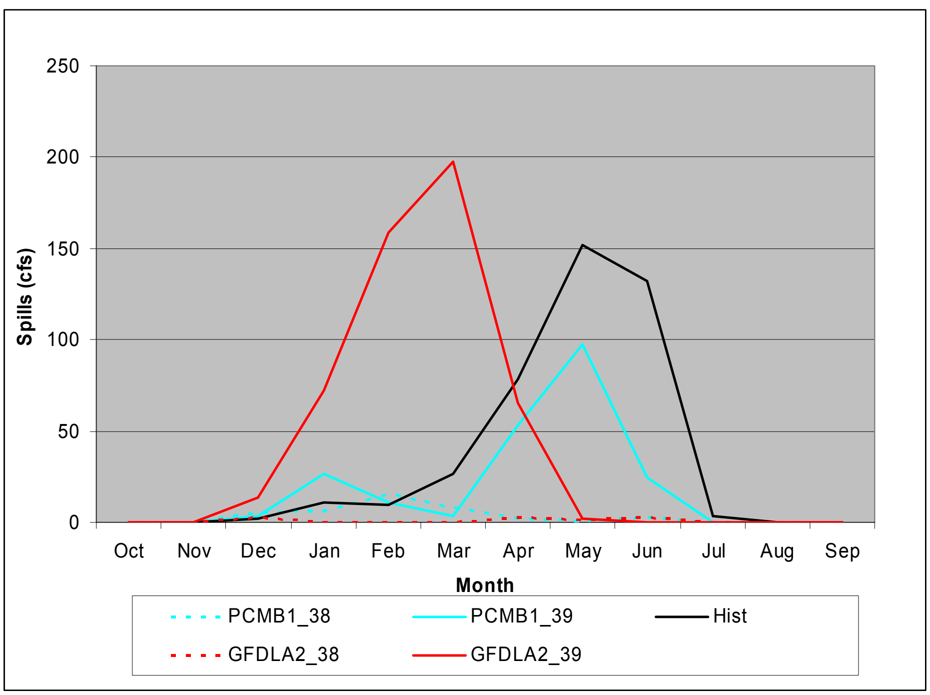


Figure 10. Spills: comparison of scenarios

Another interesting finding is that the change in timing of inflows has a smaller than expected negative impact on hydropower generation in this system. If we compare, for example, the PCMB1_39 and GFDLA2_39 scenarios we see that even though both systems have comparable drops in annual inflow the latter has a larger drop in generation revenues than the former. However, the differences are smaller than expected considering that scenario GFDLA_39 has a larger shift in monthly timing of inflows and a greater shift in time of occurrence and magnitude of high inflows to the system compared to scenario PCMB1_39. We would have expected that GFDLA2_39 would have spilled significantly more than PCMB1_39 and hence lost the opportunity to generate in the high value months of summer.

We arrive at the same conclusion when we compare the average spills from all scenarios as presented in Figure 10. A closer look at Figures 10 and 11 tells a different story though. Figure 11 shows the locations and timing of spills. We see in Figure 11 that the main system component that is spilling under both the historical and GFDLA2_39 climate change scenarios is Ice House reservoir (component 4), although it does so at different months. Looking at the characteristics of this reservoir in Table 3, we can see that Ice House Reservoir has a large relative storage capacity, and it serves as the sole supplier of water by penstock to 20 MW Jones Fork PH. However, spills from Ice House reservoir are captured downstream at Junction reservoir (below Union Valley). What is happening here is the following: forced by a constraint in penstock capacity leading to the Jones Fork powerhouse, system managers will spill at Ice House Reservoir and recapture flows at downstream reservoirs that have more generation capacity.

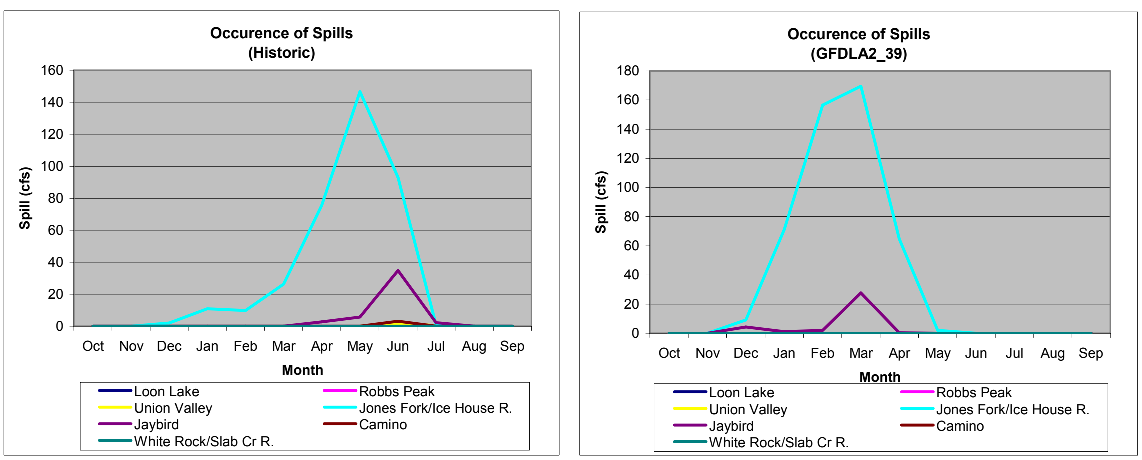


Figure 11. Spills for different components of the SMUD system

This and other constraints might be strong enough to limit the operation of the system regardless of the hydrologic conditions under which is operating. In order to study the effects these constraints have on the ability of the system to confront changes in the timing and total amount of inflow we performed sensitivity analyses of the results to changes in some of the most relevant system parameters.

3.1. Sensitivity analysis

The operation of a hydropower generation system depends not only on the hydrologic conditions of the basin but also on the characteristics of the infrastructure such as reservoir, powerhouse, and conveyance capacities. In order to explore how these different components might affect our results under climate change-induced hydrologic and hopefully extract information that can be applied to different systems, we performed a sensitivity analysis on some model parameters representing the system's infrastructure.

Following the discussion at the end of the previous section, the first parameter we looked at was the penstock/generation capacity of Ice House reservoir/Jones Fork powerhouse. The results for both the historical and climate change conditions show that spills were occurring at this powerhouse not because of constraints in the reservoir capacity but rather due to constraints in the generation capacity. In Figures 12 and 13 and Table 6 we show the results for a run in which the penstock flow capacity and powerhouse generation were both increased by a factor of five. The result of reducing this constraint is a reduction in spills from the Ice House reservoir, as expected from the previous analysis. Results in terms of generation revenues are similar to the original case without the change in parameter, which could imply that the water spilled in the first case generated energy using idle capacity in downstream reservoirs. This result speaks about the ability of a highly interconnected system to deal with constraints and changes that might occur in isolated portions of it.

Table 6. Change in annual output from the system (as absolute value and as a percent of historical output) with increased penstock capacity at Jones Fork/Ice House.

	Generation				Average monthly
	Dollar/year		MWh/year		Spills (cfs)
Historical	37671000		1440321		4
PCMB1_38	28722300	76%	1028912	71%	0
PCMB1_39	33596000	89%	1245100	86%	1
GFDLA2_38	25984000	69%	914569	63%	0
GFDLA2_39	33078600	88%	1232339	86%	3

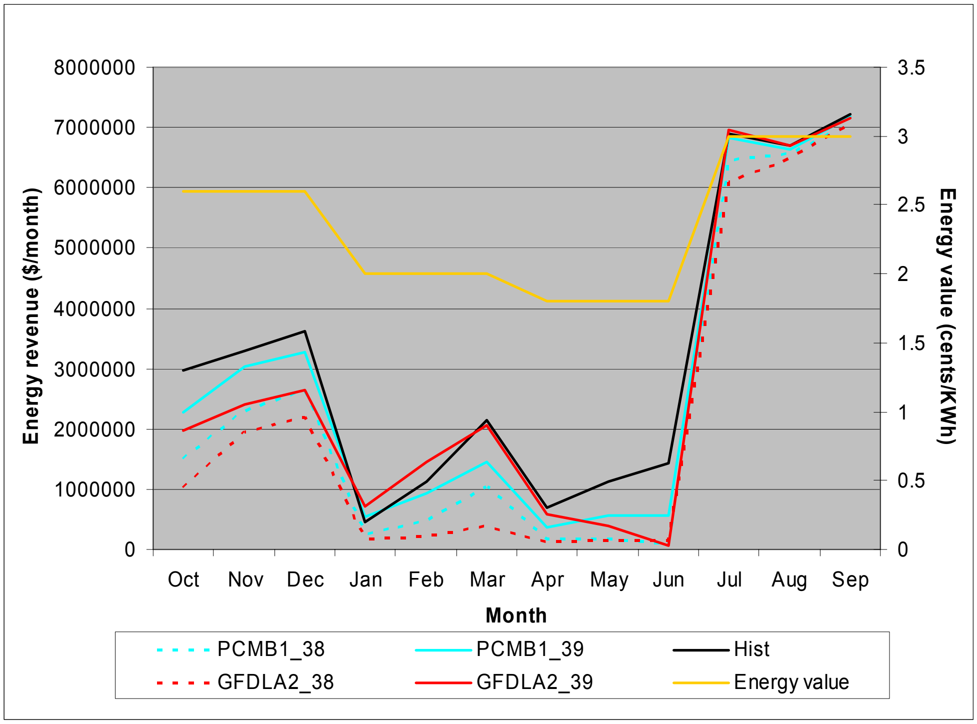


Figure 12. Energy revenues: increased penstock/generation capacity at Jones Fork/Ice House

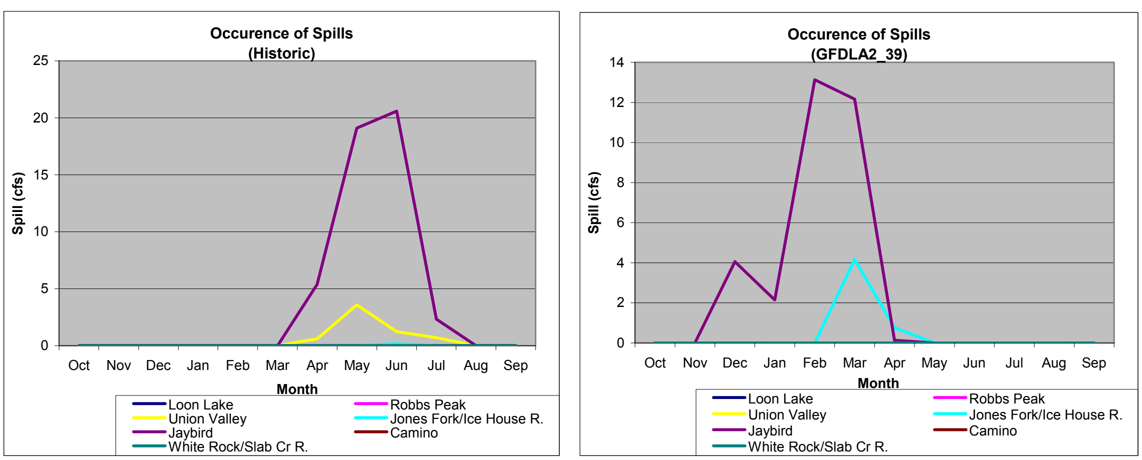


Figure 13. Spills for different components of the SMUD system with 5-fold increased penstock & generation capacity at Ice House Reservoir & Jones Fork PH

Another parameter we wanted to explore in this analysis is the effect that storage capacity has on the ability of a high elevation hydropower system to deal with changes in hydrologic conditions. In the case of SMUD's Upper American River project, the hydropower system is composed of a complex set of 11 interrelated reservoirs with a storage capacity of more than 400,000 AF, a value that represents almost 80% of average annual inflows into the system (this includes inflows to Union Valley and Ice House reservoirs and inflows from Rubicon River and South Fork American River). How would a different system with a different storage capacity behave under the same hydrologic scenarios? We study such effects by running two more scenarios, one in which all reservoirs in the system are doubled in size and one in which all reservoirs are reduced to a fourth of their size. The results of these two scenarios are shown in Figures 14-16 and Table 7. In terms of MWh of electricity generated and associated revenues, the results show as expected that doubling the size of reservoirs increases generation and that reducing them to a fourth of their size decreases generation. Generation patterns under a doubling of the reservoir size matches more closely the pattern of energy value, i.e. the system increases generation during the months of fall and early winter as compared to the original case (compare Figures 8 and 14). On the other hand, the generation pattern under a reduced storage capacity scenario more closely reflects hydrograph pattern, with an increase in late winter and spring generation/revenues as compared to the original case (compare Figures 7, 8 and 15). If we push this to an extreme of no storage capacity we will reach a scenario under which generation happens at the exact same pattern as the inflow pattern. This reflects the benefits of storing water and moving streamflow in time from a less to a more valuable month.

Table 7. Changes in annual output from the system (as absolute value and as a percent compared to historical output) for a doubling and a quartering of system storage capacity

Climate scenario	Doubled Generation Dollar/year		MWh/year		Average Monthly Spills (cfs)	Quartered Generation Dollar/year		MWh/year		Average Monthly Spills (cfs)
Historical	39302000		1468197		5	28735000		1284313		226
PCMB1_38	29989220	76%	1060806	72%	0	23432000	82%	1003963	78%	31
PCMB1_39	35055000	89%	1275340	87%	0	26020000	91%	1148144	89%	127
GFDLA2_38	27176535	69%	947650	65%	0	20853100	73%	887674	69%	28
GFDLA2_39	34278000	87%	1254625	85%	18	25573100	89%	1118420	87%	172

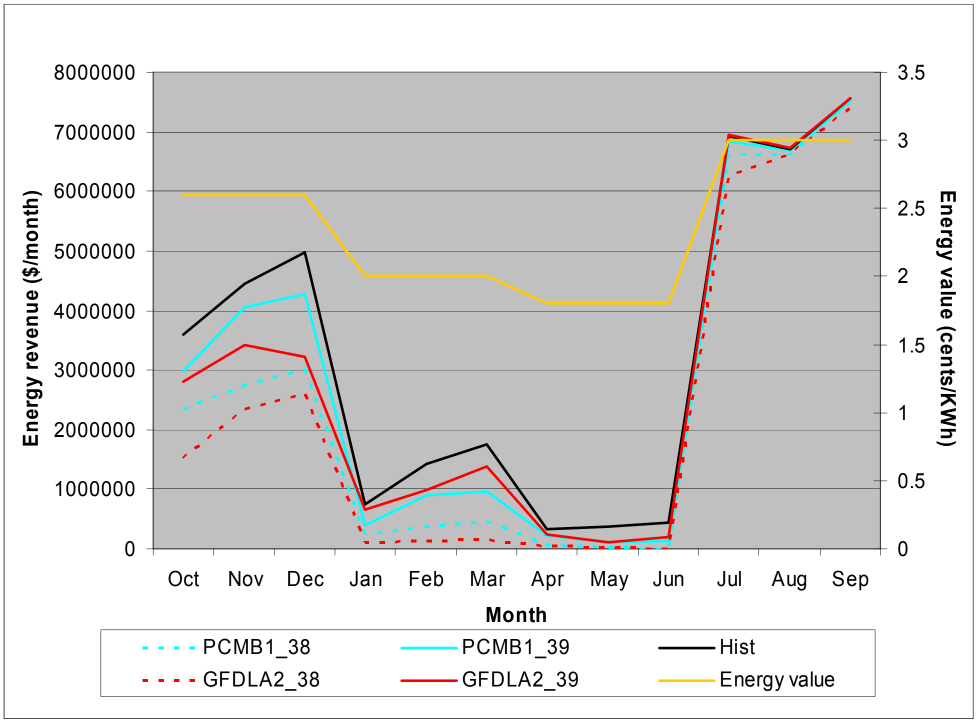


Figure 14. Energy revenues: doubling reservoir capacity

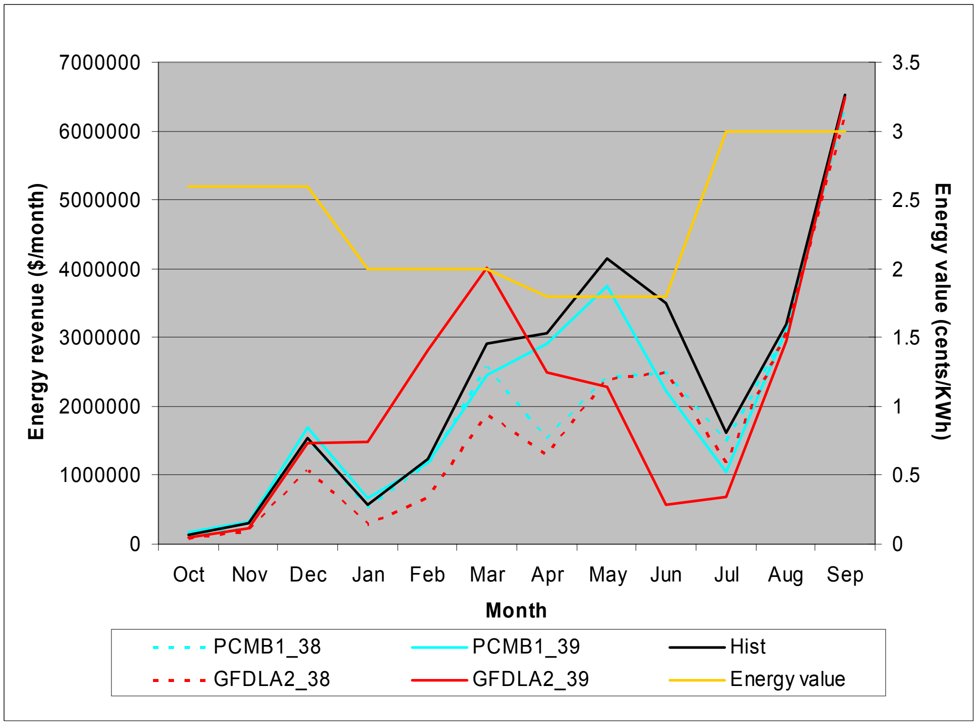


Figure 15. Energy revenues: quartering reservoir capacity

In terms of the amount of spills the results are as expected, i.e. they decrease under the doubling scenario and increase under the reduced storage scenario. When looking at the components of the system most prone to spills (Figure 16) for the quartering scenario we see that they mostly happen to reservoirs which have downstream reservoirs capable using the spilled water to generate if they have idle generation capacity. (Only those spills happening to system components 2 and 7 exit the interconnected system.)

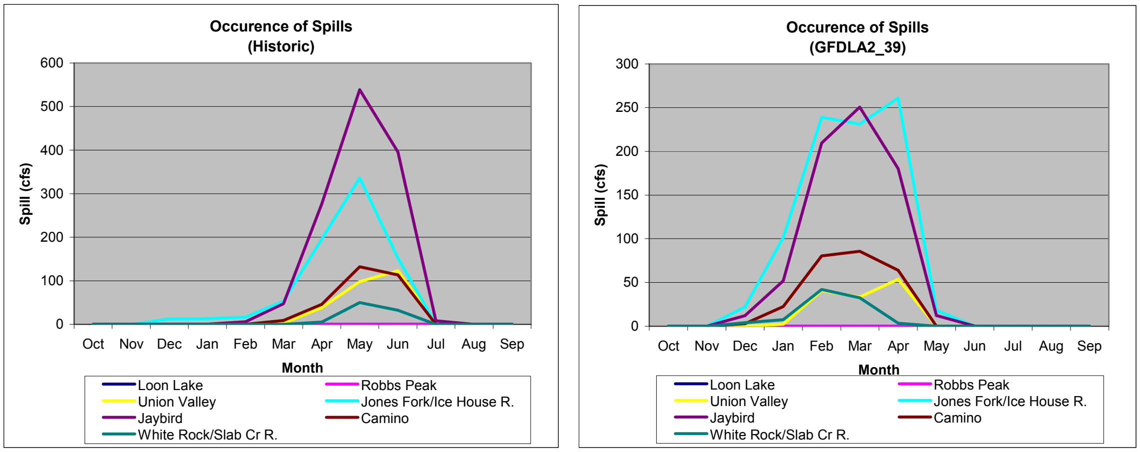


Figure 16. Spills for different components of the SMUD system: a quartering of reservoir capacity

We do not yet see a large disparity in the impacts due to different climate change scenarios that can't be explained mainly by changes in annual streamflow conditions. That is, even under very stressed conditions in terms of reduced storage capacity there is no clear effect of changing the timing of inflows or of having a different pattern of high flow events. One last set of scenarios was run to explore why we are not seeing the expected change in impacts associated with the change in timing of stream flows.

The two last scenarios we considered slightly changed the pattern of energy prices. As can be seen from Figures 8, 9, 14 and 15 the pattern of energy prices shows a markedly high value during July through September, a middle value during October through December and a low value the rest of the year. The two new scenarios considered both the doubled and quartered storage capacity conditions but with the energy price in June raised from 1.8 cents/kWh to 3 cents/kWh. The results from these new scenarios are shown in Table 8 and Figures 17 and 18. The different pattern is quite notable.

When we look at the case were the reservoir capacities are doubled we see that the system makes use of that extra capacity to store more for generating in June. The pattern of generation closely resembles the pattern in energy prices as seen already in our previous set of runs. It is in the case where the storage capacity is significantly reduced where we finally see a higher relative impact for those climate scenarios that show the greatest change in streamflow timing. Focus again on the PCMA1_39 and GFDLA2_39 cases. As can be recalled from Table 2 these two scenarios have similar reductions in terms of annual inflows but different pattern in hydrograph conditions (GFDLA2_39 has a much earlier timing of inflows). Now we see that the change (drop) in energy generation revenues under GFDLA2_39 is much higher than the drop under PCMA1_39. This is the first case in which we see an impact on energy value that is greater than the impact on energy generation. The reasons for this are evident if we compare the streamflow conditions under these two climate change scenarios. In Figures 6 and 7 we see that June unimpaired flow is almost non-existent under GFDLA_2 but still there is some flow left under PCMA1_39. The reduced storage capacity did not allow the system to store that water under GFDLA_2 and it had to generate during the less valuable winter and spring, following the timing of inflow.

Table 8. Changes in annual output from the system (as absolute value and as a percent of historical output) for the scenarios with doubling and quartering of system storage capacity and modified June energy price (from 1.8 to 3 cents/kWh)

Climate scenario	Doubled Generation Dollar/year		MWh/year		Average Spills (cfs)	Quartered Generation Dollar/year		MWh/year		Average Spills (cfs)
Historical	40926000		1473339		5	31102000		1280730		231
PCMB1_38	31143960	76%	1073966	73%	0	25178000	81%	1002035	78%	33
PCMB1_39	36163400	88%	1272980	86%	0	27536000	89%	1147129	90%	127
GFDLA2_38	28119050	69%	956655	65%	0	22561900	73%	883960	69%	30
GFDLA2_39	35627000	87%	1266391	86%	18	25956200	83%	1117438	87%	172

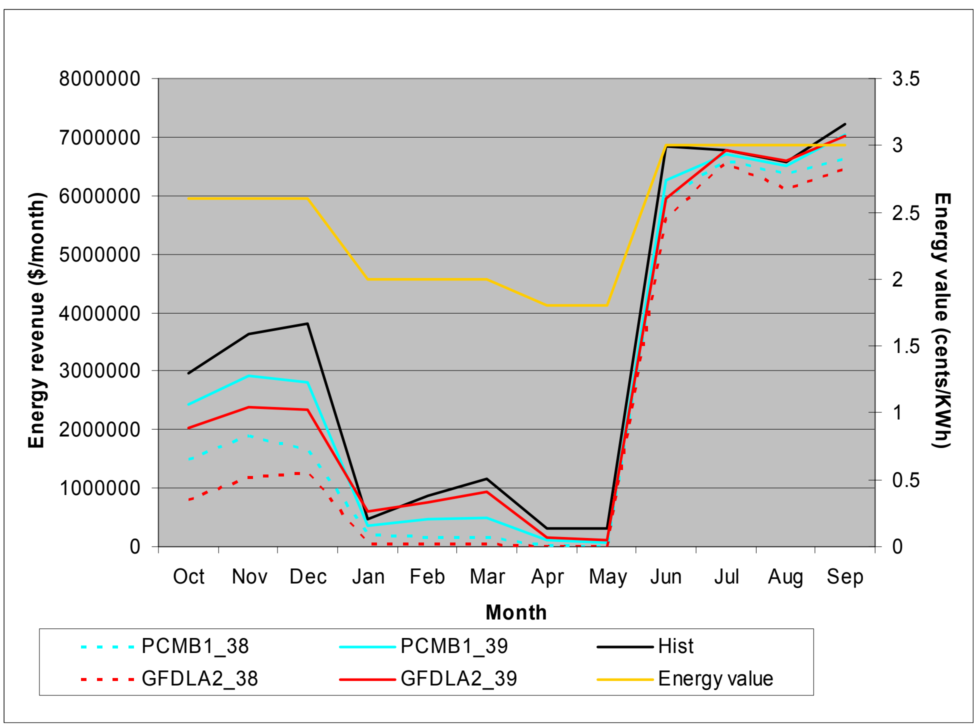


Figure 17. Energy revenues: doubled reservoir capacity and increased energy value in June

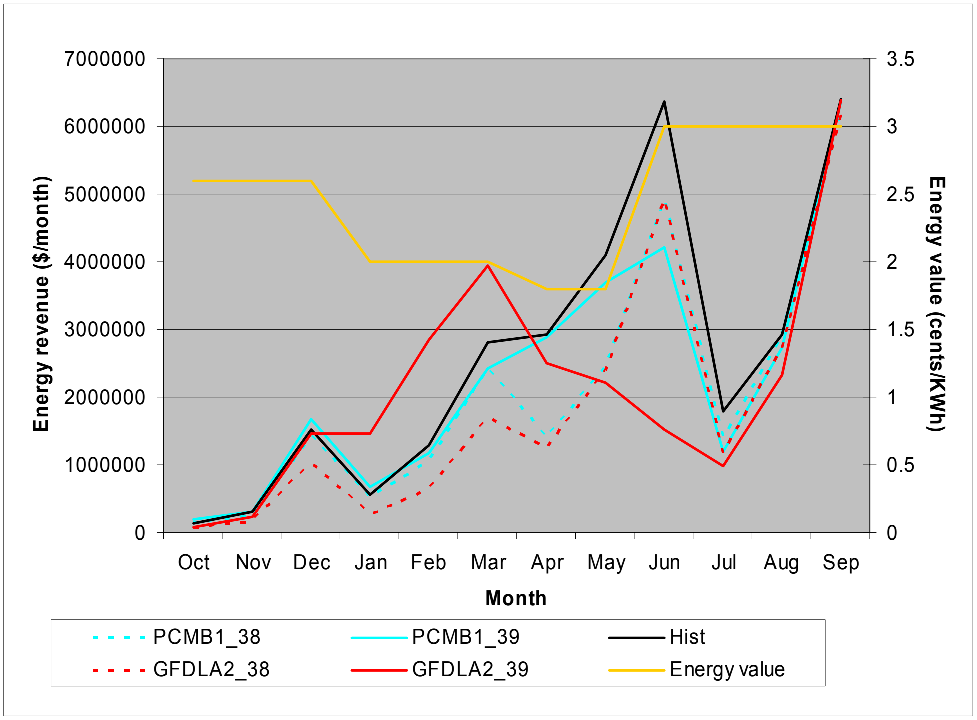


Figure 18. Energy revenues: a quarter of reservoir capacity and increased energy value in June

4.0 Conclusions

In an effort to understand the possible impacts of climate change on high elevation hydropower generation in California we developed a linear programming model of a simplified representation of 11-reservoir hydroelectric system operated by the Sacramento Municipal Utility District in the Upper American River Project. Hydrologic conditions under climate change scenarios were developed from hydrologic result predicted for nearby locations by the Variable Infiltration Capacity model run using climatic output from 2 GCMs under 2 emissions scenarios.

The results show that hydropower generation, in terms of energy generated and revenues, drops under all climate change conditions as a consequence of drier hydrologic conditions. The drop is greater in terms of energy generation than in terms of energy revenues, reflecting the continued ability of the system to store water when energy prices are low for use when prices are high (July through September). There was no clear effect in terms of different relative impacts associated with either changes in the timing of inflows or the magnitude and occurrence of high flows. It was expected that a hydrograph with inflows far from the high value months in summer would have led to lower energy revenues. Similarly it was expected that a scenario with greater flood events in winter would have led to increases in spills during the winter months and hence losses of stored water to be used during the high value months.

In order to understand why our assumptions were wrong in first place we did a sensitivity analysis of different aspects of the system. One of the parameters we changed was the overall storage capacity of the system. Changing this parameter we performed a "doubled" and a "quartering" capacity runs. The results from these runs showed that under an increased storage capacity energy generation revenues closely match energy prices, while under a reduced storage capacity energy generation revenues match streamflow conditions. However we didn't see a different relative impact associated with different timing conditions associated with the climate change conditions.

It was only when we changed the energy price for the month of June through a last set of runs that we saw the timing effect we were expecting. The reason for this is the following: the model we run originally had a very low energy price in June (1.8 cents/kWh) as compared to the energy prices in the three following months July-September (3 cents/kWh). The historical streamflow scenario does not have significant unimpaired inflows in the summer months from July-September (the last month with significant inflows being June) so a change in timing associated with the climate change scenarios is not going to affect the conditions in these high value months (reducing a very low flow will still be very low). So a change in peak in runoff from May to April does not affect the operations of this system. When we increased the energy price in June, the change in timing "did" have an effect in total revenues from this system.

Another issue we understood through this sensitivity analysis is that the system as modeled in this project can handle high flow events minimizing the amount of water spilled without passing through the turbines. Two are the major aspects that contribute to this ability to handle high flow events:

The first are the several reservoir interconnections existing in this system that allowed the use of water spilled in one reservoir (that has reached some capacity constraint) to generate in the same month using a reservoir downstream with idle capacity.

A second aspect is the approach we have used to formulate our LP problem, which assumed that the system will perfectly accommodate the predicted changes in inflow patterns. If the hydrologic pattern were to change dramatically we would expect impacts larger than the ones suggested here, because the system will be operated for a certain period using the same "rules" it had followed under the historical conditions. Another problem is associated with the perfect foresight we have assumed the system has in terms of daily streamflow conditions within a month horizon. This level of perfect foresight helps the operation of the system to accommodate the advent of high flood events in a rather unrealistic way.

As the result of this project we would expect that hydroelectric systems located in basins with significant inflows close to summer months will be affected by the timing effects associated with climate change conditions, provided they lack sufficient storage capacity to accommodate these changes. If the system has sufficiently large storage capacity these timing effects should not affect its generation capacity. There is still more work to be done to fully investigate the effects that a change in maximum flows might have on the operation of the system. This will require a better representation of the uncertainties faced by the operators of the systems and will be included in future refinements of the model used in this effort.

5.0 Future work

Recognizing some of the limitations of our paper, in future work we will modify the analysis conducted here to incorporate the following improvements:

Perfect foresight: In order to better assess the implications of different pattern of high flow events we will refine the model used in this project to include a smaller time horizon for the daily optimization (5-7 days) that will better reflect the uncertainties associated with flood events and will better capture their associated impacts under a climate change scenario. We will also perform a statistical analysis to better define high flow events into the SMUD's system.

System representation: In order to have a better sense of operational constraints in the SMUD hydro electric system we will disaggregate the 3-reservoir system that is fed by the Rubicon River (i.e. Rubicon, Buck Island and Loon Lake reservoirs).

Energy prices: The monthly pattern of energy prices is a key driver of the optimization of the LP modeled developed. For this project we used data available from CALVIN model formulation. As future refinements of the model we will reconsider the values used by analyzing historic energy prices.

6.0 References

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Appendix A

The LP formulation for this problem is the following:

$$\underset{\mathrm{Rel}_i^d,\mathrm{Rel}_i^m}{Max}\left(\sum_{d=1}^{dmonth}\sum_{i=1}^{nres} Energy_i^d * c^t + \sum_{m=1}^{nmonth}\sum_{i=1}^{nres} Energy_i^m * c^m\right)$$

s.t.

$$Energy_i^d = 24 * Power_i^d$$
$$Energy_i^m = 24 * 30 * Power_i^m$$

$$Power_i^d = \min\left[\mathrm{RelUnits}_i^d * H_i * 9.8 * eff_i, MaxPower_i\right]$$
$$Power_i^m = \min\left[\mathrm{RelUnits}_i^m * H_i * 9.8 * eff_i, MaxPower_i\right]$$

$$\mathrm{Res}_i^n + \text{Inflow+SpillsAbove+ReleaseAbove-Spills-Releases-Outputs} = \mathrm{Res}_i^{n+1}$$

(some reservoirs receive spills and releases from upstream reservoir, some don't)

$$0 \le \mathrm{Res}_i^n \le \mathrm{CapRes}_i$$
$$0 \le \mathrm{RelUnits}_i^n \le \mathrm{CapRel}_i$$
$$\mathrm{SpillMin}_i^n \le \mathrm{SpillUnits}_i^n \le \mathrm{CapSpill}_i$$

where,

Res_i^n is reservoir i storage in period n with a maximum of CapRes_i

$\mathrm{RelUnits}_i^n$ are releases through penstock from reservoir i in period n (in m^3/s). These are constrained by CapRel_i

$\mathrm{SpillUnits}_i^n$ are releases from reservoir I not passing through penstock (this could be spills, intentional in stream releases or minimum instream flow requirement releases - $\mathrm{SpillMin}_i^n$). These releases are constrained to be smaller than $\mathrm{CapSpill}_i$